Fred.Olsen Renewables

Fred. Olsen Renewables Ltd
2nd Floor
64-65 Vincent Square
London
SW1P 2NU

March 10th 2011

By e-mail to :-
EMR-condoc@decc.gsi.gov

Department of Energy and Climate Change
3 Whitehall Place
London
SW1A 2AW

Dear EMR Team,

Re: Fred. Olsen Renewables Ltd. Response to "DECC Electricity Market Reform"

Thank you for allowing us the opportunity to comment on this particularly important consultation.

Fred. Olsen has been involved in wind power since the 1990's with presence in Norway, Sweden, UK, Ireland and Canada. Fred Olsen Renewables Limited (FORL) has 315MW of operational onshore wind projects, a further 165MW consented in the UK, a number of projects in development and a further 1100MW consented offshore in the Irish Sea. In addition, FORL are RenewableUK, SRF, IWEA and NOW Ireland members and FORL staff continue to be involved with numerous industry working groups.

Our response is split in to two sections, general comments and answers to the specific questions raised in the consultation document.

General Comments

Firstly, we support the Government's objective of decarbonising electrical generation in the UK but have concerns that the proposals will not deliver the desired results. Despite the wishes of the Government, we believe a hiatus is being caused with significant unintended consequences identified and these need to be addresses swiftly. We currently have two onshore projects of some 100MW due to be operational in 2013 and are already seeing delays to the financial close and therefore to planned construction and generation. We believe a number of other developers are impacted in this way. The current hiatus is putting the already challenging 2020 target trajectory at considerable risk. Decisive action is needed to bring confidence back to the market.

As a Renewable developer and generator we do not believe that a case has been adequately made to move away from the RO. We believe that the proposed Electricity Market Reform should be *at least* as effective as current arrangements. The RO is understood by the investment community and has a successful track record demonstrated by over 5GW of installed capacity in the UK. The UK must remain attractive for investment and we have concerns that the proposals, especially Fit with CFD, will be seen as overly complex and deter investment.

The RO has not only encouraged the incumbent utilities to invest but also brought in other large European generators (Dong, Statoil, Statkraft, EDP) into the UK market. In addition to the large European generators a number of smaller Independent Power Producers (IPP) have also established themselves (Fred. Olsen Renewables, Falck, RES) together with many smaller development companies. Also our experience is that within the investment community the RO is well understood and ultimately financeable. The RO has demonstrated that it meets one of the Government's key criteria in bringing in new entrants.

We also believe by eliminating the obligation the Government has lost a key tool in meeting its 2020 targets by pushing the targets down to the supply companies. We also have concerns that without an obligation we will see a tightening of terms and reduction in long dated contracts currently offered by the utilities to IPP's.

We believe that a key driver for movement away from the RO is to provide support for other low carbon generation. We see no reason why a separate support mechanism could not be put in place for Nuclear and Carbon Capture and Storage. We also believe that the proposed measures are rushed, without full consultation with the industry and all the unintended consequences assessed.

We strongly oppose the use of auctions for FIT's. Tenders have a poor track record in other countries and we believe they will harm investor confidence and do not support new entrants.

It is important that should a FiT proposal proceed, choice must be given to allow projects under development to be able to choose between the RO and FIT for a transitional period.

We are concerned that the long lead time for large-scale projects means that an accreditation deadline of 2017 equates to no choice at all due to the length of time between financial close and first generation. The lack of a smooth transition to a new and untested support mechanism is likely to result in further hiatus in investment. To that end we would support a movement for accreditation under the RO to 2020.

As a developer, we are very concerned about the attractiveness perceived by Government for its preferred CfD proposal. In particular we are concerned that the basis risk between the index on which the CfD is struck and the income that can be realised by a generator is greater for wind plant than for the other low carbon technologies.

We believe that the CfD as outlined fails to provide a hedge against the policy risk associated with wind "cannibalisation" of electricity income and against imbalance costs, leaving wind projects disproportionately exposed to uncertainties over which they have little or no control.

Our strong preference would be to continue with the RO but failing that the Premium FIT for the following reasons:-

- It is the closest substitute to the RO and so allows for easier transition and avoids unexpected and unintended consequences.
- Does not rely on liquidity reforms required for the CfD. While still exposing developers to market risk (lower electricity prices) it does provide upside which is an important factor when making investment decision.

- Issues around access to the market and transaction cost (discount to the market price) still exist but as only part of the income stream is reliant on the electricity price this will not significantly hinder financing.

A number of difficulties arise with a CfD FIT in relation to wind generators :-

- Access to index - a longer term average electricity price index is difficult for wind generators to access as they do not know with certainty the volume of their generation in advance. Selling power against long term indices will expose wind generators to excessive imbalance exposure and greater basis risk between the price used to determine CfD payments and the market into which they are able to sell their power.
- Transaction costs - for non-Balancing and Settlement Code parties.
- Counterparty risk - the two-way nature of a CfD means that it places substantial risks on both parties to the CfD. In commercial CfDs this can require both parties to secure forms of credit to be held against the mark to market risk. As most wind generation is project-financed, whether at construction, or as refinanced utility projects after operation, the generator may have no recourse to a large balance sheet, and may have to raise funds for credit purposes.
- Wind 'cannibalising' its own revenues - as wind penetration in the market increases, electricity prices will increasingly be determined by the volume of wind generation in each period, with lower prices in windy periods and higher prices in non-windy periods, such that the average income of a wind generator can decline over time.
- As the market is currently structured, to take away Market Risk and provide floor price generators it will need to sell against a clear and transparent Market Reference Price index. This market does not currently exist and we have little confidence that the current OFGEM workstream will provide it. Due to variability wind will always be a price taker and without greater liquidity and guaranteed access IPP's will still need to sell generation through the existing utilities, so will still be subject to significant discounts to the market price.
- Overall we believe that the CfD mechanism is far more difficult to explain then the RO so will deter rather than encourage new investment.

We believe that careful design of a FiT with CfD, through the use of an appropriate liquid short term electricity price index could allow its shortcomings to be addressed but the resulting complexity and unfamiliarity of the support scheme, when compared to competing schemes elsewhere across Europe, is likely to add to the perception of risks associated with the sector and will not result in the expected reduction in the cost of capital.

In our view a capacity mechanism proposed will not be effective. We believe that more focus should be put on system flexibility as this is far more important than wholesale capacity. We believe that untargeted capacity payments may result in plant which is inflexible and can only operate under limited conditions. This has been the experience of EirGrid in the Republic of Ireland. We believe that National Grid as System operator would be a better vehicle for ensuring system security by contracting with generators for medium and long term STOR (short term operating reserve) contracts. This would be a simple extension of the process that is already running.

In addition, we believe that the Government should take this opportunity to allow for non-REZ (UK Renewable Energy Zone) renewable projects to be connected directly to the GB grid system and be able to access the UK support mechanism therefore assisting the UK in meeting its carbon reduction targets. This would be consistent with the EU Renewable Energy Directive "joint project" methodology.

Conclusion

To avoid a further hiatus in investment, FOR believes that the clear statement that the RO will be retained for Renewables development is required. Government should then consult on a separate mechanism for nuclear and carbon capture and storage.

If Government is set to introduce a new mechanism for all low carbon generation then :

- The existing RO should be extended to 2020
- Any new regime should have some form of obligation on electricity suppliers
- A premium FIT would be our preferred option
- A fundamental change to provide liquidity and access to market would be required before a CFD could be introduced.

Answers to the specific questions raised

1. Do you agree with the Government's assessment of the ability of the current market to support the investment in low-carbon generation needed to meet environmental targets?

We recognise the need to reform the market to accelerate delivery of a low-carbon economy. We are strongly of the view that the Government must work closely with the renewables industry on the detail and delivery of the mechanism it decides to implement. A great deal of work is required to minimise the current levels of market uncertainty caused by the EMR which is already causing hiatus in investment in renewable generation projects.

3. Do you agree with the Government's assessment of the pros and cons of each of the models of feed-in tariff (FIT)?

In reviewing the Governments assessment and discussing it with trade bodies and other developers we have come to the conclusion that we do not agree with the Government's assessment on the following items:

- Hurdle rates: we do not accept Table 4's results for the reduction in hurdle rates for wind energy under a CfD. The table implies that a CfD FIT reduces risk to the same extent as a Fixed FIT. This cannot be true if, as implied in paragraph 31, a CfD leaves generators exposed to short-term market prices (which a Fixed FIT does not), and when a CfD leaves wind generators exposed to wind cannibalisation and to rising balancing and imbalance costs. These risks impose a much greater cost than the hedge to fuel prices a CfD would provide.

- Investor attractiveness: the statement in paragraph 36 that "Fixed FIT and CfDs might be more attractive to a wider group of investors - in particular to smaller independent generators and institutional investors" is incorrect in respect of CfDs for both groups. Our view and that of our investors is that CfDs are seen as unfamiliar and with new risks, which have the potential to add rather than reduce costs.

- Risk: we disagree with the description of risk in Table 5 as it applies to wind and other types of variable generation. We do not believe that a Premium FIT reduces policy risk for wind generators relative to the baseline under the RO.

- Liquidity and offtake risk: there is no consideration in treatment of risks of the impact of removing the obligation on suppliers that exists in the baseline. In the absence of a liquid electricity market, the present obligation strengthens the ability of independent generators to secure a route to market for their electricity generation. This is generally achieved through the use of PPA's, which also serve as the means of managing and partially mitigating exposure to balancing and imbalance costs:
  - under a premium FIT and CfD, generators will still need to secure a route to market for their generation and be required to manage their imbalance exposure, but without any obligation on their potential counter parties to provide such routes. We would like to see some sort of obligation to be included in the future consultation.
  - unless a substantially more liquid market develops, we believe these routes will come at a higher cost than at present, potentially offsetting any identified benefits in moving renewable generators from the baseline under the RO.

4. Do you agree with the Government's preferred policy of introducing a contract for difference based feed-in tariff (FIT with CfD)?

We do not believe that the proposal is workable but believe it is possible to design a CfD that would work for wind and intermittent generation if the fundamental basis of the UK energy trading process is changed from a bilateral market to a pool type market, as adopted in other EU states. This has not been considered in the consultation and we believe is fundamental to the introduction of a CfD.

5. What do you see as the advantages and disadvantages of transferring different risks from the generator or the supplier to the Government? In particular, what are the implications of removing the (long-term) electricity price risk from generators under theCfD model?

As a general principle, risk is best allocated to the party best placed to manage it. Risk within the control of generators should be managed by them, whereas risk outside the generators' control should be transferred to another body, if that other body is better able to manage it. Under this principle, imbalance risk should be transferred to the system operator who is best placed to manage energy flows nationally. We question whether the CfD presented in the Consultation Document would remove long-term electricity price risk for generators. Under a CfD total income would be fixed according to a strike price. A generator may only be exposed to differences between an index of electricity prices and its electricity income, but this does not mean that basis risk is removed. For wind, the basis risk can be substantial.

6. What are the efficient operational decisions that the price signal incentivises? How important are these for the market to function properly? How would they be affected by the proposed policy?

Variable renewable generation cannot always respond to higher price signals and generate greater volumes when prices rise. Due to the very nature of wind generation, it is not clear that there are market efficiencies for variable generation under the CfD. Moreover, exposing wind and marine generation to short-term price signals also leaves them exposed to long-term policy risk of wind cannibalisation, a risk that cannot be hedged in the market.

7. Do you agree with the Government's assessment of the impact of the different models of FITs on the cost of capital for low-carbon generators?

We do not agree with the Government's assessment of the impact from different models of FIT's on the cost of capital. We believe the cost of capital (hurdle rate) reductions for wind projects under a CfD FIT, listed in Table 4, are not accurate. The Consultation uses generic rates of return for wind projects. Even ignoring that every project has its own cost of capital, the rates suggested may overstate the potential reduction in the cost of capital for wind projects from a CfD FIT.
Moreover, the table implies that a CfD FIT reduces risk to the same extent as a fixed FIT. This cannot be true if, as stated already, in our response under Question 3, the CfD leaves generators exposed to short term market movements, to balancing risk and to the policy risk of wind cannibalisation.

There are a number of risks and costs that do not appear to have been considered in the assessment of a CfD:

- index-basis risk
- offtake transaction costs
- counterparty credit requirements.

8. What impact do you think the different models of FITs will have on the availability of finance for low-carbon electricity generation investments from both new investors and the existing investor base?

We consider price stability is only one risk and that the critical factors in the availability of finance for low carbon electricity investments are the returns available to low carbon generators and the assessment of all relative risks perceived in the projects.
These other risks include:

- *Construction risk* from over-runs and capital costs
- *Technical* risk *in the operation and availability of capital equipment (the generator)*
- *Cost rises* related to fuel (where appropriate) and operations and maintenance and decommissioning costs
- *Foreign exchange risk* for projects where most of the capital equipment is imported
- *Market risk* related to volatility of income from the wholesale electricity market, predominantly driven by uncertainty over future gas, coal and carbon prices
- *Balancing risk* related to short-term balancing costs and cash-out pricing for uncontracted volumes
- *Liquidity risk* from uncertainty that there will be sufficient demand for the generation – to ensure that the generator can access a market for its generation at a reasonable cost – either directly or through a PPA

- *Policy risk* is related to future changes in support via carbon prices to the form, structure and level of the FIT and the ability of low carbon generation to realise income from the wholesale electricity market as the carbon intensity of the marginal generator declines and as wind generation volumes become correlated to periods of lower electricity prices.

The proposals as currently formed only address price risk. If finance for low generation remains scarce, as is likely to remain the case given the scale of investments required across Europe to 2020 (and globally over the long term), the perception of risk of investment in the UK and between technologies will play a vital role, with higher relative returns required to attract equity from outside the UK, from sovereign wealth and pension funds and low relative risk needed to attract the broadest range and lowest cost debt finance from offshore.

Fixed FIT
A Fixed FIT removes exposure to market, liquidity and balancing risks. The familiarity of Fixed FIT schemes may allow a greater volume of finance to become comfortable with the support scheme. However, Fixed FITs carry policy risk and are no longer perceived to be as reliable as they once were. The transparency of the full level of support in a Fixed FIT may mean that a Fixed FIT is more exposed to political risk than other forms of support where only the resource cost (net of the income from the wholesale electricity market) is visible.

CfD FIT
The CfD FIT proposed in the Consultation has the potential to remove market price risk from wind generators but would still leave them exposed to liquidity, balancing and policy risks. Volume risk is not overcome in the absence of effective liquid markets. To manage their overall risk exposure, wind generators would need to contract bilaterally in the market for consolidation and balancing services and for long-term price hedges (floors), as they do presently under the RO. A two-way CfD FIT also introduces credit risk that may require both the generator and the offtaker to post credit to cover the mark-to-market risk in the CfD. For financing purposes, the generator's credit requirement could increase the cost of finance that needs to be raised, while the counterparty risk may limit the number of suitable offtakers. It ought to be possible to design a CfD that would mitigate much of the liquidity, balancing and policy risks (indexed to very short-term spot markets, with Government as a counter party, and capped imbalance). However, this is also likely to result in complexity, whereby the CfD may be perceived as relatively risky by financiers due to their lack of familiarity with it.

Premium FIT
A premium FIT does not provide a hedge to market, liquidity, balancing or policy risk. To manage their risk exposure, wind generators would need to contract bilaterally in the market for consolidation and balancing services and for long-term price hedges (floors), as they do under the RO. However, the relative simplicity of concept and international familiarity with the premium FIT approach may mean it is, for financiers, the most acceptable of the FIT options outlined by DECC.

9. What impact do you think the different models of FITs will have on different types of generators (e.g. vertically integrated utilities, existing independent gas, wind or biomass generators and new entrant generators)? How would the different models impact on contract negotiations/relationships with electricity suppliers?

Fixed FIT

Utilities

We believe a Fixed FIT is not favoured by utilities supplying power in the UK market which act as suppliers not project developers. The sale of output to a central agency, as occurs under other fixed FIT programmes, is viewed by participants in the UK market as too interventionist.

New entrant generators

For offshore wind and marine technologies, where there remains substantial uncertainty over the development, construction and on-going operations and management costs of these technologies, the lock-in of a fixed income stream may reduce the cost of debt by reducing the overall risk profile of the investment. The disadvantage of a Fixed FIT in this case, however, is that it may be unattractive to equity investors who may perceive a lack of upside to return on investment.

CfD FIT

New entrant generators

A CfD FIT has the potential to remove market price risk from wind and marine generators but could still leave them exposed to offtake risk, in the absence of an obligation on suppliers to purchase their output. However, it may be possible to design a CfD that would mitigate the liquidity, balancing and policy risks for wind and marine technologies by indexing to short-term spot markets and with the Government acting as the counterparty to CfD's.

The impact of CfD's on contract negotiations and relationships with electricity suppliers

Most renewable generators currently choose to contract bilaterally with traders or suppliers to access the electricity market, consolidation and balancing services, and to sell embedded benefits such as Levy Exemption Certificates (LEC's). This applies equally to independent generators and to projects developed by utilities that have since been refinanced as independent entities. The contracts may vary from long-term fixed price PPA's to short-term routes to market that pass market and imbalance prices through to the generator but as a common feature provide the volume certainty by which generation can be sold. Wind and marine generation, because of their variable generation profile, present greater imbalance and 'shape' risk than baseload generation and are therefore less attractive to a supplier as a procurement option. Wind and marine generators also sell power at a discount, to sign a PPA, with smaller discounts as the PPA provides hedging to imbalance or to market price. Longer durations also transfer additional risk from generators to offtakers.

There is concern that under the CfD FIT, wind and marine generators may find it harder to conclude contracts with suppliers. While the RO may not have provided a strict obligation to purchase power, it has provided a significant incentive to purchase renewable power. Generators ineligible for renewables obligation certificates (ROC's) generally find it harder to get PPA offers from providers and without PPA's projects struggle to raise finance for construction.

To ensure that renewable generators are able to continue contracting bilaterally under a FIT, it has been suggested that a new obligation be placed on suppliers to procure low carbon electricity, potentially through suppliers' fuel mix declarations and that prescribe declining carbon intensities. What is unclear is the nature of the penalty that would apply.

10. How important do you think greater liquidity in the wholesale market is to the effective operation of the FIT with CfD model? What reference price or index should be used?

Market liquidity is vital to the success of the CfD. For a CfD to provide an effective price hedge the generator must be able to sell its power into the indexed market; otherwise it will be exposed to price risk between the value of the income it receives and the market value used to settle the CfD.

If liquidity is not improved in the electricity market, low carbon generators may be exposed to high transaction costs in accessing the market.

Fred. Olsen Renewables would prefer to see proposed changes to the existing market arrangements brought within the EMR process rather than being run by Ofgem in parallel workstreams that are focussed on new entry by small suppliers. DECC appears overly reliant on Ofgem to provide solutions to offtake risk.

We feel that this is a high-risk strategy. If market liquidity is to remain a key part in the EMR process then we believe that DECC will have to legislate in this area.

11. Should the FIT be paid on availability or output?

We acknowledge the potential for using availability as a measure for payment, to solve the problem of negative pricing (as low carbon generators paid in this way would not be incentivised bid down below zero in periods when generation needs to be constrained). However, there are a number of issues with this approach which make it appear unattractive:

- Use of availability as a basis for payment increases the complexity of the system, further deterring wider participation from new entrants.
- Renewables targets in the Renewable Energy Directive are set on the basis of energy volumes and a FIT set on the basis of output is best aligned to this.
- Determining availability for wind, which is based on technical and resource availability, is complex whereby using output would be simpler.
- Payment on availability basis risks unintended consequences.

It would be better to pay the FIT on the basis of output only. It would certainly be helpful to have a mechanism to deal with the issue of negative pricing, but we do not believe this is the correct way to deal with this.

Options for Market Efficiency and Security of Supply

19. Do you agree with our assessment of the pros and cons of introducing a capacity mechanism?

We do not believe that the Government has made the case for a capacity price mechanism; rather it has assumed that one is required to meet a perceived shortfall in capacity. We agree that a capacity price mechanism has the potential to offer investors in eligible plant greater certainty in revenues, thereby improving the investment case. However, we are also concerned that there is a risk that a capacity price mechanism may 'pollute' energy markets. This is expanded on in Question 21.

The provision of energy flexibility is required, which is to meet the increasing system needs for power ramping, rapid response, short run times and low cost start up and shut down. These services function in addition to other ancillary services such as reactive power, voltage response and frequency response. EirGrid, which has experience of running its system on 50 per cent wind power and of capacity mechanisms, is quite open in saying that it would like to see generation earning less capacity revenue in future and an increase in payments to ancillary services. What is key is that the System Operator is able to contract flexible plant to meet operational needs. The STOR (short term operating reserve) mechanism is already in place and should be extended to medium and longer term STOR contracts.

20. Do you agree with the Government's preferred policy of introducing a capacity mechanism in addition to the improvements to the current market?
We do not support the introduction of a capacity mechanism. We are concerned that the legislative route this requires would make such a mechanism highly inflexible and lock customers into paying for something in the future regardless of need. Longer term ancillary services contracts should be developed before capacity payments are considered.

21. What do you think the impacts of introducing a targeted capacity mechanism will be on prices in the wholesale electricity market?

In theory, a carefully designed, targeted support scheme should not have an impact on prices in the wholesale market. In practice, however, the provision of capacity support may distort price setting in the market. Peaking plant, whose fixed costs are recovered through the capacity mechanism, may be able to participate in the market at short-run marginal cost, undercutting merchant providers and potentially diluting price signals at peak times. This could reduce the value that all generators are able to earn from generating at peak periods and may dissuade commercial investment in peak capacity outside of the capacity mechanism, perversely increasing the need for the capacity mechanism to expand capacity.

22. Do you agree with Government's preference for the design of a capacity mechanism:

- ***a central body holding the responsibility;***
- ***volume based, not price based; and***
- ***a targeted mechanism, rather than market-wide.***

FORL does not support the implementation of a capacity mechanism for reasons given above.

23. What do you think the impact of introducing a capacity mechanism would be on incentives to invest in demand-side response, storage, interconnection and energy efficiency? Will the preferred package of options allow these technologies to play more of a role?

We note the Government's reference to demand management and energy efficiency in the Consultation Document and welcome this emphasis. Therefore, we do not see how a capacity mechanism will do anything other that skew the market away from demand side participation.

It is likely interconnectors will play an important role in providing "capacity" as well as facilitating the future export of energy from renewable generation and smoothing electricity price variations. The proposed capacity mechanism could discourage such investments.

24. Which of the two models of targeted capacity mechanism would you prefer to see implemented:

- ***Last-resort dispatch; or***
- ***Economic dispatch.***

We do not support the introduction of a capacity mechanism as previously mentioned. If government pushes through with a capacity mechanism, we would support last-resort dispatch, as it is less likely to distort the electricity market price.

25. Do you think there should be a locational element to capacity pricing?
We do not support any locational element in capacity pricing for the following reasons:

- It confuses the need for capacity to meet a shortfall in energy with locational signals to mitigate network constraints:
- Locational capacity payments add additional complexity, reduce liquidity and may penalise plant located away from demand which is able to meet capacity needs.

Analysis of Packages

26. Do you agree with the Government's preferred package of options (carbon price support, feed-in tariff (CfD or premium), emission performance standard, peak capacity tender)? Why?

We have no comment on emission performance standard.

We believe a Premium FIT provides the least uncertainty to renewable generators; is closest in design to the RO; and will provide the least disruption to current and planned investments.

We believe any carbon floor price should operate on the principle of increasing support. It should start at a low level and rise gradually to provide confidence in it as a genuine means to support and as projects come on-line in the latter part of this decade.

27. What are your views on the alternative package that Government has described?

We believe that the introduction of a Premium FIT is likely to be more effective than the CfD FIT in catalysing an increase in renewable energy's share of low carbon generation to 2020 and beyond. It is the easiest-to-understand of the FIT's proposed in the Consultation, in that it resembles the RO; however, as stated previously, there are issues around offtake, liquidity and the lack of an obligation on suppliers that are not addressed in the Consultation.

28. Will the proposed package of options have wider impacts on the electricity system that have not been identified in this document, for example on electricity networks?

All economic reform implemented on the scale outlined in the EMR carries the risk of unintended consequences. The Government's proposal for a capacity mechanism, if carried out, may result in the retention of capacity that is neither flexible nor responsive. The proposal would appear to overlook the needs of both the networks and the system operators.

29. How do you see the different elements of the preferred package interacting? Are these interactions different for other packages?

For wind generators the critical element of the package is the choice of an effective FIT mechanism. While we have concerns that the capacity price mechanism could have a negative impact on the electricity market, these concerns are less under the preferred package (centralised targeted approach) combined with last resort dispatch, than the alternatives proposed.

Implementation Issues

30. What do you think are the main implementation risks for the Government's preferred package? Are these risks different for the other packages being considered?

The main implementation risk for the CfD is that it is too complex. It is more complex than systems in other countries, thereby deterring investors. Either an average price index is used, that hedges against market risk but leaves variable renewable generators open to balance risk, or a short-term price index is used that is significantly more complex and expensive to operate, and in any case may be impractical for smaller generators. The CfD may also require the establishment of new agencies to administer its operation. The implementation risk of the premium FIT is likely to be less than that posed by the CfD. The premium FIT also presents a lower-risk option in the face of calls at the European level for the harmonisation of support for renewables, with premium FIT-type models being discussed.

31. Do you have views on the role that auctions or tenders can play in setting the price for a feed-in tariff, compared to administratively determined support levels?

- ***Can auctions or tenders deliver competitive market prices that appropriately reflect the risks and uncertainties of new or emerging technologies?***
- ***Should auctions, tenders or the administrative approach to setting levels be technology neutral or technology specific?***
- ***How should the different costs of each technology be reflected? Should there be a single contract for difference on the electricity price for all low-carbon and a series of technology different premiums on top?***
- ***Are there other models government should consider?***
- ***Should prices be set for individual projects or for technologies***
- ***Do you think there is sufficient competition amongst potential developers/sites to run effective auctions?***
- ***Could an auction contribute to preventing the feed-in tariff policy from incentivising an unsustainable level of deployment of any one***

particular technology? Are there other ways to mitigate against this risk?

Auctions

We are strongly of the opinion that auctions to set the level of support for low-carbon generation would act as a major barrier to investment. With our experience in the 1990s of the use of auctions under the non-fossil fuel obligation (NFFO) system, we do not believe that auctions reveal 'true' prices, with the result being large-scale non-delivery of contracted projects: only about 30 per cent of contracted NFFO wind capacity was delivered.

Auctions increase development risk

The most serious implication of auctions is the effect the may have on development risk. At present, a renewable developer can invest in all the processes required to gain consent and grid connection, in the knowledge they can access the RO and with confidence about the level of reward available. With an auction system in place, however, the developer cannot have confidence that support will be available to their project, since they may fail to secure a contract through the auction process. This is because developers cannot be clear if or at what level of support their projects will receive from an auctioning process.

There are also considerable transaction costs to participating in tenders which could deter smaller players from taking part. If projects are expected to enter tenders early, ahead of planning permission, then developers will have to devote resources to both consents and contracting at the same time, reducing the number of projects they can work on. While if tenders are entered later after planning, then developers will be expected to sink costs into projects without knowing what rewards they will get, if any. If, in order to deter unrealistically low bids, there are significant penalties for non-delivery, then again this may have a significant impact on small developers' willingness to participate at all. Tenders will also introduce a stop-start element to the renewable sector, with developers having to wait until the next tender round before proceeding with projects. This makes business planning difficult and leads to inefficient use of resources.

In general auctions add another step into the development process, further delaying delivery of renewable capacity. Auctions do not assist in bringing still maturing technologies to market. The NFFO experience for onshore wind, with its emphasis on cost reduction before technology constraints had been fully worked through, led to unrealistic bidding and lack of delivery.

We believe that auctions designed to set support levels would severely reduce the attractiveness of the UK as a development destination, particularly in comparison to countries that do not use competitive processes in their support mechanisms.

Auctions have not worked elsewhere

Evidence from other countries where this approach has been tried is mixed. The Netherlands is quoted in the Consultation Document, but its tender in 2009-10 represents a clear case of market failure.

Competitive tenders elsewhere have not worked. These tenders favoured higher risk but ostensibly cheaper bids. There was no flexibility to revisit more conservative bids that were not successful initially, when lower priced bids failed to deliver. There were insufficient penalties for non-delivery, nor enough attention given to bidders' track record and finances.

Given clarity on the levels of capacity from each technology, it should be possible to set levels of support so that appropriate amounts of development take place.

32. What changes do you think would be necessary to the institutional arrangements in the electricity sector to support these market reforms?

If the CfD is adopted, there will need to be some kind of central agency that acts as the counterparty, to minimise counterparty risk and to obviate the need for generator to post credit at an additional cost.

In parallel with the wider market reform process, DECC is examining the role of Ofgem. We believe that Ofgem has focused too narrowly on network operation and has not taken into sufficient consideration the impact of grid availability and cost on the ability of the UK to meet targets for renewables and carbon emissions.

To target flexibility and grid availability over capacity as an objective, in lieu of capacity payments as we have suggested in this submission, National Grid would need to let STOR contracts of a longer duration that one year, so as to promote investment in flexible plant.

33. Do you have view on how market distortion and any other unintended consequences of a FIT or a targeted capacity mechanism can be minimised?

The best way for the Government to avoid or minimise any unintended consequences of FIT or targeted capacity payment mechanism would be for it to maintain an open dialogue with the industry on the detailed design and implementation of its chosen FIT (or targeted capacity mechanism).

34. Do you agree with the Government's assessment of the risks of delays to planned investments while the preferred package is implemented?

We believe hiatus has already been caused and there is significant risk of further hiatus in investment during the transition to the preferred package, simply from a decrease in investor confidence in renewable generation as a result of uncertainty. The CfD may assist in stabilising revenue flows over the long term, but this is a moot point if, over the next decade, planned investment does not go ahead or has to be refinanced at higher margins, due to perceived risk and uncertainty over the implementation of many of the EMR's core proposals.

We believe that Government should consider extending the RO to 2020 and continue to consult with industry on a suitable replacement once issues of liquidity have been addressed.

35. Do you agree with the principles underpinning the transition of the Renewables Obligation into the new arrangements? Are there other strategies which you think could be used to avoid delays to planned investments?

A point of preliminary accreditation has been used in the past for eligibility under the RO, in relation to banded-down landfill gas generators. In this case, new landfill gas generators were able to preserve 1ROC/MWh, rather than 0.25ROCs/MWh, if they received preliminary accreditation before April 2009, followed by full accreditation (at the point of commissioning) before April 2011. This precedent could be used for allowing projects that receive pre-accreditation by 31 March 2017 to qualify for ROC subject to achieving full accreditation by 31 March 2020.

We also note the potential impact of change on income from the sale of LEC's currently earned by UK renewable energy projects in the RO. Our understanding, from discussions with HM Treasury, was that this system will be grandfathered. This is critically important because most of the renewable energy projects financed in the UK under the RO have been project financed under long-term contracts in which the LEC revenue was included.

36. We propose that accreditation under the RO would remain open until 31 March 2017. The Government's ambition to introduce the new feed-in tariff for low carbon in 2013/14 (subject to Parliamentary time). Which of these options do you favour:
- All new renewable electricity capacity accrediting before 1 April 2017 accredits under the RO;
- All new renewable electricity capacity accrediting after the introduction of the low-carbon support mechanism but before 1 April 2017 should have a choice between accrediting under the RO or the new mechanism.

The key issue with the transition between the RO and the new system of low-carbon support is that the RO is approved by accreditation after the point of first generation, whereas the new mechanism is granted earlier in the project cycle, presumably at financial investment decision (FID), when the developer signs contracts for major equipment. Consequently, if the RO is being closed to new entrants in April 2017, then investment decisions need to be made well in advance of this date if the scheme is to be accessed in time. At the very least, developers must be able to sign the new contracts before 2017, even if they cannot be activated until that date.

The long lead-time for many projects means that a RO accreditation deadline of 2017 may exclude a number of offshore wind projects currently under development. This issue could be solved by granting an initial pre-accreditation status to any project that intends to use the RO and commences construction by the 2017 cut-off date.

In order to reduce the risk of an investment hiatus and to allow developers to access the new system and become comfortable with it before the RO closes, we believe developers should be allowed to choose between the two systems. Given the issue described above, however, the period where there is an effective choice between the two systems may be short. If the lead time between investment decision and generation is three years, which is typical for offshore wind projects, then the window of choice is only one year at best, assuming that the choice of system is essentially fixed when investment decisions are made.

It is possible that developers could decide to invest in a project on the understanding that it would enter the RO, and then opt to sign a FIT contract later, but that option may be limited to players financing projects from their balance sheets.

Developers using project financing would have created a contract structure around the RO which would have to be unpicked and refashioned in order to change schemes in mid-build, which in turn leads to risk of legal issues under PPA's and default clauses being triggered in loan agreements. The effective window of opportunity to choose would be even shorter if FIT system implementation were to be delayed. Government is projecting that the contracts would be available to sign in April 2013, but this is only 24 months away from the end of the Consultation, and the White Paper must be issued, primary and secondary legislation passed, and new structures created before the new system is implemented. The risk here is that the April 2013 date slips and the FIT will not be available until 2014. For projects that take a long time between investment decision and generation, there will be little or no effective choice unless there is some flexibility about projects' ability to enter the RO around the April 2017 cut-off.

It should also be noted that large-scale projects may take up to five years from the start of generation to completion and that under recent modification of the RO projects can phase in grandfathering over a five year period. However, under the transition arrangements proposed, large scale projects will not receive 20 years of support under the RO for all turbines in the project; the end of the RO in 2037 could result in some turbines receiving as little as 15 years of support. This will make the economic case under the RO very difficult to approve for major projects seeking FID in 2013-14 and demonstrates that, in practice, there is unlikely to be a realistic choice of mechanism for these developers. We urge the Government to extend the RO beyond 2037 for this type of project, to ensure that there is no delay in financial investment decisions in the period 2013 - 2015

37. Some technologies are not currently grandfathered under the RO. If the Government chooses not to grandfather some or all of these technologies, should we:

- ***Carry out scheduled banding reviews (either separately or as part of the tariff setting for the new scheme)? How frequently should these be carried out?***
- ***Carry out an "early review" if evidence is provided of significant change in costs or other criteria as in legislation?***
- ***Should we move them out of the "vintaged" RO and into the new scheme, removing the potential need for scheduled banding reviews under the RO?***

We would prefer to see non-grandfathered technologies to be moved to the new FIT scheme. This would not only remove the need for banding reviews for the vintaged RO, it would make forecasting the number of ROCs in the market easier, which would be beneficial when using headroom to set the Obligation level post-2017, which is our preference.

38. Which option for calculating the Obligation post 2017 do you favour?

- ***Continue using both target and headroom***
- ***Use Calculation B (Headroom) only from 2017***
- ***Fix the price of a ROC for existing and new generation***

It is feasible to continue with the current mechanism to set the Obligation using both target and headroom. We recognise, however, that up to the end of the RO in 2037, it is possible projects still in the scheme will be over-rewarded if the obligation is not allowed to fall to zero. The second option (using Calculation B only) does allow the target to fall towards zero if there is little forecast renewable output within the remaining RO group of projects. We therefore believe that this is the only appropriate way to set the Obligation from 2017.

Converting to a fixed ROC
We believe that fixing the price of a ROC for existing and new generation would be very unhelpful. All PPA negotiations with immediate effect have to take into account the potential for this mechanism to be introduced. Fixing the price of a ROC has the potential to disrupt hundreds of PPA's that are currently in force, which, in turn, would require hundreds of bilateral legal negotiations to determine the financial winners and losers. This move would demonstrate a damaging lack of commitment from government to the notion of grandfathering.

We are open to the possibility of a hybrid system, with a move to fixed ROCs at a date between 2017 and 2037, but we would need to see a specific proposal before being able to comment one way or another. Specifically, this proposal should not be implemented at any date where any PPA that is in effect now could be damaged. This would suggest that the earliest possible date for the implementation of the fixed ROC, if at all, would be from 2027 to 2030.

It would be useful for DECC to state that all the RO's constituent parts - the indexed buy-out price, 10 per cent headroom and recycling, and banding - will be retained into the future. This would give confidence to investors that the system will be grandfathered in its entirety.

It is not sufficient to merely grandfather the RO, but to ensure that reasonable investor expectations under the RO, particularly with respect to the RO buyout price, the recycle benefit and the levy exemption certificates are maintained. The guaranteed headroom, which sets the supplier obligation, may need to be adjusted potentially both up and down.

Headroom would need to be adjusted to take account of new projects that elect the new support scheme in lieu of the RO but also to reflect any projects within the RO which might, for any reason, cease generating (for example, should one or more large offshore wind farms fail for technical reasons and cease generating ROC's, the headroom would need to be adjusted downwards to avoid windfall profits to the remaining generators through increased recycled benefits).

Any changes in law must respect existing contracts. A large number of existing RO projects have been financed using long term project finance provided by the banks. Most of those project financed projects rely on 12 to 15 year PPA's between the projects and, generally speaking, the 'Big Six' utilities. Effective grandfathering requires that all of these contracts remain in full force and effect and that the benefits which are expected to flow to the parties do not change. Broadly speaking, this means that any grandfathering cannot act to void or terminate any of the existing contracts between RO generators and the major utilities.

Grandfathering needs to take into account the fact that most project financing loan documents allow the lending banks to declare loans to be in default in certain circumstances, typically:

- Change in law or regulation which would have a material impact on the expected economics of the investment.
- Termination of any material contract on which the project financing is based, specifically including the termination of any power sales contract between a generator and utility.
- Change in regulation or law which would lead to the loss of either RO accreditation or any material permit.

Finally, we seek reassurance that provision has been made for sufficient resource within DECC to see this process through from this initial fact finding stage through to delivery and implementation of the EMR conclusions.

If you have any comments or require further clarification on any of the points raised in this response, please do not hesitate to contact me.

Yours sincerely,

[redacted]

[redacted]

Fred. Olsen Renewables Ltd.

renewableUK